D.P.U./D.T.E. 97-81

Petition of Boston Gas Company and Massachusetts LNG, Inc., pursuant to G.L. c. 164, § 69I for approval of their 1997 Long-Range Resource and Requirements Plan for the five-year period beginning November, 1997 through October, 2002

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I. INTRODUCTION AND PROCEDURAL HISTORY

On August 1, 1997, pursuant to G.L. c. 164, § 69I, Boston Gas Company ("Boston Gas" or "Company") filed with the Department of Public Utilities, now the Department of Telecommunications and Energy ("Department"), a petition for approval of its long range resources and requirements plan for the five-year period beginning November 1997, through October 2002. The petition was docketed as D.P.U./D.T.E. 97-81.[(1)]

Boston Gas is primarily a regulated natural gas distribution utility. The Company serves utility customers in the City of Boston and 73 other cities and towns in eastern Massachusetts. The Company's combined natural gas distribution service areas cover approximately 81 cities and towns. Of its over 500,000 customers, approximately 92 percent are residential customers.

The Attorney General filed a notice of intervention pursuant to G.L. c. 12, § 11E. Pursuant to notice duly issued, the Department conducted a public hearing and procedural conference in Boston on December 18, 1997. On January 26, 1998, Industrial National Leasing Corporation, Inc. ("INLC") filed a late petition to intervene which was granted on February 13, 1998.

Evidentiary hearings were held at the Department's offices on March 26, 1998, and March 30, 1998. Boston Gas sponsored the testimony of two witnesses: A. Leo Silvestrini, the manager of gas resource planning for the Company; and Theodore Poe, Jr., a consultant for the Company. INLC sponsored the testimony of one witness: William H. Nau, a consultant with Travers & Nau.

The evidentiary record includes numerous exhibits and responses to record requests. The parties filed both initial and reply briefs. Subsequent to the filing of reply briefs, Boston Gas filed a letter with the Department stating "we are authorized to state that, while INLC is not in any way assenting or agreeing to the accuracy of any factual or legal assertion by the Company in the Filing, INLC no longer opposes the Filing of the Department's approval thereof." Letter from Boston Gas Company regarding INLC, at 1, June 24, 1999.

II. ANALYSIS OF THE LONG-RANGE FORECAST

A. Standard of Review

Pursuant to G.L. c. 164, § 69I, the Department is required to ensure "a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." In accordance with this mandate, the Department reviews the long range forecast of each gas utility to ensure that the forecast accurately projects the gas sendout requirements of the utility's market area. G.L. c. 164, § 69I. A forecast must reflect accurate and complete historical data, and reasonable statistical projection methods. G.L. c. 164,

§ 69I; 980 C.M.R. § 7.02 (9)(b). Such a forecast should provide a sound basis for resource planning decisions. Colonial Gas Company, D.P.U. 96-18, at 4 (1996); Bay State Gas Company, D.P.U. 93-129, at 5 (1996); Holyoke Gas and Electric Department, D.P.U. 93-191, at 2 (1996); Berkshire Gas Company, 16 DOMSC 53, at 56 (1987).

In its review of a forecast, the Department determines if a projection method is reasonable based on whether the method is: 1) reviewable, that is, contains enough information to allow a full understanding of the forecast method; 2) appropriate, that is, technically suitable to the size and nature of the particular gas company; and 3) reliable, that is, provides a measure of confidence that the gas company's assumptions, judgments, and data will forecast what is most likely to occur. D.P.U. 96-18, at 5; D.P.U. 93-129, at 5; D.P.U. 93-191, at 2; Haverhill Gas Company, 8 DOMSC 48, at 50-51 (1982). Specifically, the Department examines a gas company's: 1) planning standards, including its weather data;

2) forecast method, including the forecast results; and 3) derivation and results of its design and normal sendout forecasts. See D.P.U. 96-18, at 5, and D.P.U. 93-129, at 5-6; D.P.U. 93-13, at 6; see also, Boston Gas Company, D.P.U. 94-109 (Phase 1), at 9 (1996). As part of the review of the forecast, the Department also examines the company's scenario analysis, which is used for evaluating the flexibility of the company's planning process, including any cold-snap[(2)] analysis and sensitivity analysis. Boston Gas Company, 25 DOMSC 116, at 200 (1992) ("1992 Boston Gas Decision"); see D.P.U. 93-129, at 23-25 and D.P.U. 94-109

(Phase 1), at 61-66.

B. Previous Sendout Forecast Review

In Boston Gas Company, D.P.U. 94-109, at 20-22, 25 (1996), the Department approved Boston Gas' sendout forecast subject to several conditions. In that decision, Boston Gas was directed to:

1) review the design-day standards of similarly situated utilities ("Order One");

2) survey the attitudes of Boston Gas' customers regarding cost and reliability ("Order Two");

3) use the Company's load data to improve its analysis and assumptions regarding the relationship between load and temperature with in its design-day ("Order Three");

4) address weaknesses in the assumptions the Company used in developing its design-day standard ("Order Four"); and,

5) modify the Company's assumption regarding the number of days of interruption by narrowing the range between the high- and low-avoidable cost scenarios.

The Company's compliance with Order One through Order Four is addressed in Section II(C)(2), below. The Company's compliance with Order Five is addressed in Section II(C)(3), below.

C. Planning Standards

The first element of the Department's forecast review is an assessment of a company's planning standards because of their critical importance to a forecast. A company's planning standards are used as a basis for projecting its sendout forecast, which, in turn, is used for ascertaining the adequacy and cost of a company's supply plan.

The Department's review of planning standards begins with a review of a company's weather data. The accuracy of weather data is important because weather data is the basic input upon which a company's planning standards are based. The second step of our review is an analysis of the planning standards themselves -- how the company arrived at its

design-day and design-year standards. The Department reviews a company's planning standards to ensure that they are reviewable, appropriate, and reliable.

1. Weather Data

a. Description

In order to perform its statistical analysis to determine its design-day and design-year standards, Boston Gas maintains a record of daily effective degree days ("EDDs")[3] based on observations taken at the Logan International Airport weather station for the period January, 1971 to the present (Exh. BGC-1, at 13). The Company also maintains a record of the coldest day for each of the twenty-five heating seasons for the years 1971-1972 through 1995-1996 (id.). Using the data set of peak days, and assuming that the variation in weather is distributed normally, the Company established that the mean annual peak day is 66.8 EDD with a standard deviation of 5.5 EDD (id.).

b. Analysis and Findings

Because Boston Gas' current weather data is from a weather station within its service territory and is based upon data sets encompassing a substantial historical period, including recent observations, the Department concludes that Boston Gas' weather data is likely to be accurate and representative of the weather that has been experienced within the Company's service territory. In addition, the over 25-year weather database compiled and used by the Company is comparable to other databases previously approved by the Department.

See Colonial Gas Company, D.P.U. 96-18, at 7 (1998); Boston Gas Company, D.P.U. 94-109, at 10 (1996). Accordingly, the Department finds that Boston Gas' weather data is reviewable, appropriate, and reliable.

2. Design-day Standard

a. Description

Boston Gas' proposed design-day standard is 78 EDD (Exh. BGC-1, at 12). This represents a downward shift of five EDD from the 83 EDD standard approved in

D.P.U. 94-109. The Company states that the shift is a result of Boston Gas' ongoing review of planning standards including an assessment of the changing business environment and an update of the Company's analytical procedures (id.). Assuming the variation in weather is distributed normally, the Company states that its design-day of 78 EDD would occur once in every 48 years (id.).

To support the selection of its design-day standard, Boston Gas conducted a cost benefit analysis, examining the cost of outages versus the cost of maintaining reliable service. The Company's analysis measures the probability-weighted costs resulting from gas curtailments (i.e., avoidable costs) against the cost of procuring additional resources required to meet expected load during extreme weather (id. at 13).

The Company determined the costs of curtailments to residential and commercial and industrial ("C&I") customers separately (id. at 13-14). For residential customers, the Company calculated the probability-weighted[(4)] costs of damages associated with two categories of avoided costs: 1) relight expenses[(5)] and 2) freeze-up costs.[(6)] The probability-weighted costs of service disruptions to C&I customers is based on the product of the economic cost per day[(7)] for one day's interruption (id. at 14).[(8)] Two damage scenarios were established, with 25 percent and 75 percent of the C&I customer base being affected (id.).

The Company limited the analysis by estimating two different sets of potential costs: the low-upgrade costs and high-upgrade costs that would be incurred to meet demand at different EDD levels (id.). Graphically representing the probability-weighted costs of damages against the low and high upgrade costs, the Company defined a range for its

design-day standard of between approximately 75 and 82 EDD, based on the intersection of the curves, with a graphical midpoint of 78 EDD (id. at 14, Chart 1-A-9).

In compliance with Order Four, Boston Gas developed an Emergency Curtailment Procedure ("ECP")[(9)] establishing steps designed to maintain the integrity of the Company's distribution system and reduce disruption to customers during a curtailment situation (id.

at 14). The Company maintains, however, that the ECP can not be relied upon on as a design-day supply source. The Company asserts that this approach is in line with the Department precedent regarding electric utilities. (id. at 16, citing Petition by Attorney General, D.P.U. 87-169-A (1988)).

In compliance with Order One, the Company conducted a survey of other New England local distribution companies ("LDCs") to determine the range of design-days. The design-day standards for the twelve LDCs surveyed range between once in 20 years and once in 100 years (id. at 16, Att. C). Based on the survey results, Boston Gas maintains that the frequency of occurrence of its design-day standard (once in 47.95 years) is comparable to other similarly situated gas companies (id.).

b. Analysis and Findings

In Bay State Gas Company, 19 DOMSC 140, 158-159 (1989), the Siting Council indicated that the purpose of requiring an analysis to examine the balance between cost and reliability as they relate to planning decisions is to ensure that the utility is reasonably weighing the objectives of cost and reliability. The Siting Council posited that excessively high design criteria would cause a utility to construct facilities indiscriminately and enter into agreements to prepare for any and all eventualities. Id. at 159. Instead, an appropriate and reliable analysis ensures that the utility weighs the objectives of cost and reliability reasonably and plans for a reliable level of service, while not wasting customers' money by spending above that level. Id.

In D.P.U. 94-109, the Department recognized this tension between the conflicting goals of safeguarding reliable, uninterrupted gas service which may require LDCs to procure resources in excess of their peak requirement and ensuring that costs to the LDCs' customers are low. D.P.U. 94-109, at 25. The Department found that Boston Gas' design-day standard of 83 EDD with a probability of occurrence of once in 424 years, while reviewable and appropriate to the size and nature of the Company, was not reliable because the assumptions, judgements, and data used by the Company did not forecast what was most likely to occur. Id. The Department stated that in order for the Company's next forecast and supply plan to be approved, the Company must comply with the Orders outlined in Section II(B), above. In addition, the Department stated that in a time of increasing competitiveness, a customer should have the choice whether to pay for such an extremely reliable source of supply. Id.

At issue is whether Boston Gas has established a reviewable, appropriate and reliable design-day standard that promotes both cost-effective and reliable resource planning. The Department recognizes that the Company has taken steps to comply with the aforementioned directives. Primarily, the Company updated its analytical procedures in determining its design-day which bring the planning criteria within a more acceptable range in compliance with Order Three (use the Company's load data to improve its analysis and assumptions regarding the relationship between load and temperature with in its design-day). In compliance with Order Two, the Company commissioned a survey of customers in its service territory to determine the value that its customers placed on safe, reliable service (Exh.

BGC-1, Att. D). The Department acknowledges the importance that customers place on reliable service, further exemplified through this survey, and also notes that the Company has modified its analytical procedures to bring its design-day standard within an acceptable range. In compliance with Order One, the Company conducted a survey of the design-day standards of other similarly situated LDCs (id. at Att. 1). This survey shows that the Company's

design-day standard of 78 EDD is comparable to the design-day standards of other similarly situated LDCs (id.). The Department finds that Boston Gas has sufficiently complied with the directives set forth in DPU 94-109 and, based on the foregoing, finds its design-day standard to be reviewable, appropriate, and reliable.

3. Normal-Year and Design-Year Standard

a. Normal-Year Standard

Boston Gas analyzed the normal weather within its territory over a twenty-year period from January 1976 to December 1995 to develop a twenty-year mean temperature (id. at 12). The Company found the normal-year planning standard to be 6,522 EDD (id.).

b. Design-year Standard

The Company's design-year standard is 7,120 EDD representing a probability of occurrence of once in 38 years (id. at 17). This is a downward shift of 80 EDD from the design-year standard of 7,200 EDD approved in D.P.U. 94-109 (id.). As with its design-day standard, the Company states that the shift is due to an assessment of the changing business environment, and an update of its analytical procedures.

Similar to the support of its design-day standard, Boston Gas evaluated its design-year standard using a cost-benefit analysis. The optimal standard was defined as the point at which the probability-weighted costs of a shortage were balanced against the expected costs required to maintain uninterrupted service. A planning range of between 7,000 EDD and 7,250 EDD was determined. The Company chose the graphical midpoint of 7,120 EDD as its design-year standard (id. at 19).

The Company analyzed the effect the ECP would have on reducing the number of curtailments and potential damages. By implementing this procedure, the Company estimates that it would be able to accommodate a design-year of 7,150 EDD, representing a shift of 0.4 percent or 30 EDD (id. at 20-21). However, due to the uncertainty of the quantity of load reductions and emergency supplies it would be able to procure under the ECP, the Company used its selected design-year standard of 7,120 EDD arguing that the frequency of occurrence for this design-year standard is once in 38.17 years which is comparable to the design-year standards maintained by other LDCs in New England (id. at 21).

c. Analysis and Findings

The Company used a twenty-year period to develop its normal-year standard which is consistent with what the Department deemed acceptable in D.P.U. 94-109. Therefore, the Department finds that the method used to develop Boston Gas' normal-year standard is reviewable and appropriate. In addition, having approved the use of the Company's weather data in Section II(C)(1)(b), above, the Department finds that the normal-year standard is reliable.

The Company complied with Order Five by limiting its analysis to the peak period, which narrowed the range between the high and low avoidable-cost scenarios, thus reducing the design-year standard from 7200 EDD to 7120 EDD.

In D.P.U. 94-109, the Department found that the Company had employed conservative assumptions when establishing planning standards, generally affording customers an additional level of supply security. D.P.U. 94-109 (Phase I), at 31. In that decision, the Department cautioned the Company that as the marketplace for resources becomes increasingly flexible, all LDCs will have to evaluate the reliability of new service offerings and procure innovative options that will serve to reduce gas costs, while not jeopardizing reliable service (id.

at 30-31). This is especially true now as the LDCs are in the process of unbundling and marketers are positioning themselves to provide service to the LDCs' customers.

As competitive suppliers begin to serve customers, LDCs will have to match more closely their firm resource entitlements to changing firm requirements. LDCs should continually strive to optimize their resource portfolios and firm load requirements in a manner that promotes safe, reliable, and low cost service. Given the need to assess a broad array of resources and load-management options, LDCs will have to monitor the cost and reliability of options and conduct analyses using reasonable, up-to-date input assumptions. Given the current marketplace and Boston Gas' efforts to update its design-year analysis, the Department finds that Boston Gas has attempted to use the best information available and that its current analytical assumptions appear to be reasonable.

D. Forecasting Methods

1. Introduction

The Company applied "end-use modeling methodology" to forecast incremental demand by traditional end-users (Exh. BGC-1, at 22).[10] The Company forecasted demand by adding annual increments to its 1996-1997 normalized actual sendout (id.). Inputs for the residential sector forecast include energy consumption by household and building type, the number of households by city and building type, and the end-use distribution of energy-using equipment by building type (id.). For the C&I sector forecast, the Company used employment figures for the Company's service territory by region and Standard Industrial Code ("SIC"), oil and gas price projections, equipment and building stock energy efficiencies and equipment replacement rates (id.).

The Company also developed forecasts for its non-traditional customer segments such as natural gas vehicles ("NGVs"), seasonal firm sales made under special contracts, and natural gas used in large-scale power generation (id. at 22-23). Boston Gas combined these two forecasts to derive the total Company forecast (id. at 23). The Company noted that it applies its end-use modeling to traditional customers only (id.).

2. End-use Modeling

The Company states that its end-use method forecasts total energy demand by end-use and by fuel type, including natural gas (id.). End-use includes space heating, water heating, cooling, lighting, cooking, and drying in the residential and C&I sectors (id.).

The Company's end-use method applies a bottom-up approach that simulates individual decision making for the choice of energy equipment, energy sources and consumption levels (id.). When customers face decisions regarding equipment replacement, they choose between their existing fuel or another energy source (id. at 23-24). The Company's end-use model also simulates how consumption levels respond to changes in energy prices (id.). Thus, Boston Gas estimated the incremental energy demand for each market and determined the demand that will be met by the share of natural gas (id. at 24). The Company followed the following four-step process to forecast demand:

1) The Company determined energy demand by region, building type, end-use and fuel type (i.e., gas, electricity, and oil) based on a 1991 energy use study that incorporated Company's sales data and other sources (Exh. BGC-1, at 24);

2) The Company developed annual incremental demand forecasts beyond 1996 by market segment under normal weather conditions that take into account the separate forecasts of economic and demographic growth, fuel price developments, equipment replacement rates and equipment efficiency assumptions (id.). The Company also measured the accuracy of its forecasting model by backcasting for the 1992-1996 period (id. at 24-25);

3) The Company converted its annual demand (i.e., annual sales) estimates to sendout requirements by adjusting sales for unaccounted-for and Company-use gas (id. at 25);

4) Finally, the Company added the incremental sendout requirements to the

base-year sendout requirements to obtain total sendout requirements under normal whether conditions (id.).

3. Base Year Energy Demand

The Company established its base year total energy demand for the calendar year 1991 (id.). Total demand for the residential and C&I classes was broken down by building type, city, end-use and fuel type (id.).

a. The Residential Base Year Model

As a first step in developing the residential base year model, the Company multiplied the total number of households in its service territory by the energy consumption per household by building type (id. at 26). The Company then estimated the total 1991 base year energy demand by end-use (id.). The Company used an 1989 appliance saturation survey and electric utility regulatory filings to obtain the distribution of various energy-using equipment by fuel type (id.). Next, the Company estimated average energy use per appliance based on the data developed by the Company, Boston Edison Company ("BECo"), Massachusetts Electric Company ("MECo") and the United States Department of Energy (id.). Finally, the Company obtained the total energy demand for each appliance in the 1991 base year by multiplying the number of each appliance type by the appliance energy intensity factors (id.). Boston Gas separated the total energy demand by end-use into fuel types (electric, gas and oil) using Company data for gas sales, BECo and MECo data for electric sales with the residual considered oil sales (id. at 27).

b. Commercial/Industrial Base Year Model

The Company's C&I base year model estimates the total energy demand by city, SIC code, end-use and fuel type (id.). The forecast is based on employment projections in the C&I sector (id.). The Company relied on: 1) employment data for its service territory, 2) energy intensity factors from an A.D. Little, Inc. ("ADL") study reflecting energy consumption per employee, and 3) fuel market shares calculated by analyzing Company sales records and information provided by ADL (id.).

To derive the total energy consumption by SIC code, the Company used employment data for each code which it then multiplied by energy use factors estimated by ADL (id.). Next, the Company calculated energy consumption by end-use (id.). Thus, the Company obtained total energy demand estimates by SIC and end-use (id.). Finally, the Company estimated the shares of fuels in total energy by using a "balancing algorithm" that took into account assumptions about gas sales by SIC code from Company records, electric sales data from BECo and MECo and the relationship between fuels and end-uses (id. at 28).

4. Forecasting Annual Incremental Demand

Following the estimation of the base-year energy demand, the Company forecast annual incremental demand for each market segment, relying on the forecast values of driver variables (id.). The driver variables are economic and demographic growth rates, fuel prices and equipment replacement rates, and equipment efficiency assumptions (id.). The Company's model distinguishes between new and existing establishments (id.).

The Company's model estimated both gross and net load additions for each market segment. Gross load additions refer to increases in gas consumption due to the installation of

gas-fired equipment in all (old and new) buildings. Net incremental additions are the difference between the current year gas throughput volumes and the previous year's throughput volumes (id. at 25). The Company's net load additions take into account both load gains and load losses such as changes in gas consumption due to replacement of older equipment with newer, more efficient equipment, the effect of demand side management ("DSM") programs and fuel price elasticities[11] (id. at 28).

The Company projects that over the forecast period there will be 14,427 BBtu of gross additions to total throughput (id. at 29).[12] Net throughput additions over the forecast period total 7,863 BBtu (id.). Based on the forecast results, Boston Gas expects its sendout requirements for traditional markets to grow 12.6 percent over the forecast period, or 2.4 percent per year (id.). The Company's total throughput additions are forecast at 10.4 percent over the same period yielding a 2.0 percent growth per year (id.).

The Company presented its market segment forecasts as follows:

a. Residential Market

The Company states that in residential structures with one to four units, the annual gross and net loads will increase by an average of 878 BBtu and 540 BBtu, respectively, over the forecast period, representing an overall increase in the residential sendout of 1.1 percent per year (id. at 30). The Company forecast residential end-use demand separately for new and existing households.

i. New Residential Households

The Company's forecast for new residential households is based on projections of the number of new households and fuel choice decisions for the energy equipment in those new households (id.). In these calculations, the Company used county level forecasts adjusted for its service territory (id.). The 1997 forecast indicates an 0.8 percent growth rate in the number of households over the forecast period, by building type (id.).

Next, the Company determined the number of appliances that will be added to the newly constructed units by fuel type (id.). Finally, the Company calculated the total energy consumption by fuel type through appliance use factors and reached the annual incremental demand for new units by building size, fuel type, and end-use within the Boston Gas service territory (id. at 31).

ii. Existing Residential Households

The Company relied on simulation results of equipment replacement decisions and annual energy consumption levels among existing households (id.). The Company's appliance saturation survey provided data on energy equipment fuel type and replacement rates (id.).

The Company states that the equipment replacement decision is affected by appliance type, fuel use, replacement rate of the existing equipment and replacement market shares by fuel type for each appliance (id.). The Company's model estimates changes in energy consumption per appliance and indicates that the use per appliance among existing customers tends to decline due to the higher efficiency of new equipment (id.).

The annual energy demand for existing households was assumed to be price elastic (id.). The Company's projections for burner-tip gas prices indicate an average annual compound rate of 2.0 percent decline over the forecast period (id. at 31-32). Finally, the Company adjusted its forecast to account for Company-sponsored DSM programs (id. at 32).

b. Apartment House Market

The Company's demand forecast for apartment houses, (residential structures with five or more units) indicates that a net incremental load addition of 555 BBtu is expected over the forecast period (id.). This represents a 6.9 percent increase in sendout volume during the forecast period, or 1.3 percent per year (id. at 33). The Company used separate end-use models to forecast demand for new and existing apartment houses (id.).

i. New Apartment House Market

The Company forecast demand for the new apartment house market segment by projecting the number of new households and by simulating the fuel choice decisions for new energy equipment (id.). The Company used data for growth in the number of households by building type at the county level from DRI/McGraw-Hill and adjusted this data for its service territory (id.). The forecast for the new apartment house market indicates an average annual growth rate of 0.8 percent over the forecast period (id. at 30).

Next, the Company simulated the decision-making process of selecting fuels for new energy equipment by estimating the net present value of the cost of installing and operating energy equipment for each competing fuel (id. at 33). Then, the Company employed an algorithm developed by ADL to calculate the probabilities of outcome on the shares of gas and oil fired equipments (id.). The model also adjusted energy use factors for each appliance to reflect the higher efficiency of new equipment (id.). Finally, the Company developed the annual incremental energy consumption by fuel type and end-use for the new apartment house market (id.).

ii. Existing Apartment House Market

For the existing apartment house market, the Company used simulation results of equipment replacement decisions and annual energy consumption levels (id. at 34). The Company states that the equipment replacement decision is a function of the share of existing equipment due for replacement each year and the comparative costs of installing and operating gas-fired equipment versus alternatives (id.). Similar to the existing residential market, the Company's model estimates the change in energy consumption per appliance which tends to decline due to the higher efficiency of new equipment (id.).

The annual energy demand in the existing apartment house market, similar to the existing household market, is assumed to be price elastic (id.). The Company used fuel price projections based on DRI/McGraw-Hill commodity price forecasts, NYMEX gas and No.2 heating oil futures prices, and Boston Gas data on distribution margins and

long-haul transportation costs (id.). The Company's projections for burner-tip gas prices indicate an average annual compound rate of 2.0 percent decline over the forecast period (id.).

c. Commercial and Industrial Market

The Company's C&I demand forecast shows 6,321 BBtu of net incremental load during the forecast period (id. at 35). This represents an overall increase in C&I sendout of 28.5 percent, or 5.1 percent per year (id.).

i. New Commercial and Industrial Markets

The Company's end-use model for the new C&I markets forecasts demand on the basis of employment projections and the simulation of fuel choice decisions for new energy equipment (id.). The Company used employment projections by SIC code for its service territory which show an average annual growth rate of 1.3 percent over the forecast period (id. at 36). Next, the Company used the energy use per employee factors provided by ADL to calculate total energy demand (id.).

The Company then determined market share by fuel type for new C&I equipment (id.). The Company estimated the net present value of the cost of installing and operating energy equipment for each competing fuel (id.). Next, the Company used a choice model developed by ADL that calculates the probabilities of outcome on the share of gas and oil fired equipment (id.). The end-use model then adjusted energy use factors for each appliance to reflect the better efficiency of new equipment (id.). In addition, the model estimates the gas market share in the Boston Gas service territory (id.). Finally, the Company developed a forecast of gross energy demand for new C&I markets by SIC code, fuel type and end-use in the service territory (id.).

ii. Existing Commercial and Industrial Markets

The Company forecast demand in the existing C&I market segments by simulating equipment replacement decisions and annual energy consumption (id.). According to the Company, the equipment replacement decision is a function of: 1) the share of existing equipment due for replacement each year, and 2) a comparative cost analysis of installing and operating gas-fired equipment versus alternatives (id. at 36-37). The model takes into account efficiency levels of replacement equipment and the share of natural gas in the replacement market (id. at 37).

The Company indicates that annual demand in the new C&I markets is price elastic (id.). The Company's fuel price projections were based on DRI/McGraw-Hill commodity price forecasts, NYMEX gas and No.2 heating oil future prices, and Boston Gas' data on distribution margins and long-haul transportation costs (id.). The burner-tip gas prices are projected to decline at an average annual compound rate of 2.0 percent (id.). Although prices are expected to remain stable over the 1999-2002 period, they exhibited a sharp decline of 11 percent in 1998 causing the projected decline in the planning period (id.). Considering the negative price elasticity of gas, the Company expects an increase in consumption following the price drop of 1998 (id.).

d. Non-Traditional Markets

i. Natural Gas Vehicles

The Company forecast 1,472 BBtu of load additions in the NGV market throughout the planning period including additions from the C&I markets, government, intra-city bus and school bus fleets (id. at 38). The Company's forecast is based on its NGV marketing and investment strategy which evaluated current and future market drivers and barriers, and assessed their likely effect on Company load additions (id.). The Company's strategy targeted fleets which: 1) are mandated to convert to cleaner fuels; 2) are made up of vehicles with high fuel use characteristics; 3) can locate refueling facilities on-site rather than rely on public fueling stations; and 4) are eligible for financial and tax incentives for alternate fuel vehicles (id.).

The Company states that there are several barriers working against the development of a NGV market including restrictions on underground garage parking, a lack of accessible maintenance facilities for NGVs, a limited number of compressed natural gas refueling sites, and high capital cost to construct fueling stations (id. at 40). Also, the Company notes that NGVs face competition from electric vehicles, reformulated gasoline, and bio-diesel (id. 40).

ii. Seasonal Firm Gas Sales

The Company expects that the firm seasonal load will decrease by 2,665 BBtu by the end of 1999 as a result of the termination of the MATEP firm sales agreement (id.). However, the Company expects MATEP will convert to transportation when its seasonal firm sales contract expires (id.). Also, the sales contracts to Wellesley College and Brandeis University will be in effect throughout the forecast period (id.).

iii. Large-Scale Power Market

The Company indicates that natural gas demand for the large-scale power generation market will not affect the Company's sendout requirements or resource plan during the forecast period because: 1) all power generation previously served by the Company has converted to transportation before the date of the instant filing, and 2) the Company is not currently aware of any plans to locate a large-scale gas fired power generation plant in its territory over the forecast period that does not yet have gas requirements in place (id. at 41). The Company states that, in the event a new power plant is built, its distribution system is capable of delivering any amount of gas supplied by a third party (id.). iv. Demand Side Management

In Boston Gas Company, D.P.U. 96-50 (Phase 1) (1996), the Department directed the Company to file a proposal for its participation in energy efficient market transformation initiatives (id. at 41, citing D.P.U. 96-50 (Phase 1) at 189 (1996)). The Company estimated DSM volume reductions of 104 BBtu per year during the forecast period (id. at 41-42). The Company plans to maintain a constant overall expenditure level for DSM over the forecast period (id. at 42). The Company indicates that it is an active participant in the Gas DSM Market Transformation Collaborative formed to develop programs that will address market barriers during the transition to a more competitive market (id.).

v. Transportation Migration

The Company states that it has fully unbundled its rates and, effective December 1, 1996, has offered all C&I customers the opportunity to obtain their gas supplies through marketers (id. at 42-43). The Company states that its goal is to provide all customers with the ability to choose gas suppliers by December 1, 2000 (id. at 43). Boston Gas further states that the Department deferred consideration of the Company's proposal to exit the merchant function until the end of the LDC collaborative process (id.). The Company states that it is difficult to determine the overall effect of customer migration to transportation on its future resource requirements without having a resolution of the issues of capacity assignment and capacity management (id.).

The Company indicates that, under the mandatory capacity release mechanism approved in D.P.U. 96-50 (Phase I), customers converting to transportation receive a pro rata share of pipeline capacity and storage resources while the Company provides balancing service through its downstream assets (id. at 44). Further, the Company states that it has sufficient flexibility in its supply portfolio to handle any transportation outcome with commodity acquisitions (id.). In this regard, the Company forecast the number of migrating customers and evaluated the effect this migration will have on its resources (id.). However, the Company states that it still lacks sufficient reliable data to prepare a comprehensive transportation forecast (id. at 45). Given this limitation, the Company instead modeled an outcome by defining a base case forecast with two alternate migration scenarios (id.).

(A) Base Case Transportation Migration

The Company's base case migration scenario assumes that Boston Gas remains in the merchant function and that customers are not required to select a third-party supplier through the end of the forecast period (id.). To determine the effect of transportation migration on commodity requirements, the Company estimated the migration patterns for new and existing loads (id.). The analysis indicates that the total net annual incremental transportation volumes will increase from 5,824 BBtu in 1997 to a peak of 9,707 BBtu in 1998, then decline to 1,565 BBtu in 2001 (id. at 46).

The Company calculated these migration patterns by forecasting total throughput on its system (id.). Then, Boston Gas estimated the portion of throughput that would be delivered under transportation service (id.). The Company added net load additions from the demand forecast to the base year throughput for each market segment (id.). The Company then grouped the markets into three tiers representing similar migration patterns: 1) Tier 1 consisting of large C&I customers (Rates G-44 and G-54), who are likely to convert quickly to transportation; 2) Tier 2 consisting of medium-sized C&I customers (Rates G-42, G-43, G-52 and G-53), who are slower in converting compared to the large customers; and 3) Tier 3 consisting of the residential (Rates R-1 and R-3) and small C&I customers (Rates G-41 and

G-51), who are expected to have the slowest migration rates (id.). After calculating the total annual throughput projections for each tier, the Company estimated the portion of annual throughput that will migrate to transportation, on a tier basis (id.). Assuming unbundled sales and transportation are available to all C&I customers on December 1, 1996, and to all residential customers on April 1, 1998, the Company estimated that 90 percent of Tier 1, 50 percent of Tier 2, and 20 percent of Tier 3 will have migrated to transportation by the year 2002 (id. at 47).

(B) Scenario 1: Boston Gas Withdraws from Competitive Retail Commodity Markets

The Company's first alternate migration scenario assumes the complete withdrawal of Boston Gas from the retail gas commodity market by the end of 2000 (id. at 48). Under Scenario 1:

1) Unbundled sales and transportation are available to all C&I customers on December 1, 1996;

2) The Company will cease providing gas sales service to C&I customers on November 1, 1998;

3) Unbundled sales and transportation is available to all residential customers by April 1, 1998;

4) The Company will cease providing sales services to residential customers on November 1, 2000 (id. at 48).

Under Scenario 1, the Company states that the firm sales requirements will be zero for its C&I customers by 1999, and zero for its residential customers by 2001 (id.).

Based on these reference points, the Company interpolated the rate of transportation migration for each class (id.). This scenario assumes a sudden increase of transportation migration immediately after the unbundling of the natural gas market with slower migration activity to follow (id.). Just before the date customers are required to select third-party suppliers, a second increase of transportation migration is assumed (id. at 48-49).

The Company's calculations indicate an increase in annual incremental transportation volumes from 5,824 BBtu in 1997, to 24,608 BBtu in 1999, with a decline to 11,626 BBtu in 2001 (id. at 49). The Company states that by 2002, all of the net load growth will be attributed to transportation (id.).

(C) Scenario 2: Residential and Small Commercial/Industrial Default Service

The second alternate migration scenario assumes Boston Gas will exit the commodity markets for large and medium C&I customers (Tiers 1 and 2), and will make transportation service available to residential and small C&I customers (Tier 3), while maintaining a default sales service (id.). Under these conditions, Tiers 1 and 2 are obligated to convert to transportation. The scenario assumes 20 percent of Tier 3 customers will opt for transportation service (id.). The Company's calculations show an increase in annual incremental transportation volumes from 5,824 BBtu in 1997, to 15,315 BBtu in 1998, and a decline to 1,829 BBtu in 2002 (id. at 49-50).

(D) Effect of Transportation on Resources

The Company states that its supply plan is capable of optimizing its portfolio continuously given the demand levels represented by the alternative transportation scenarios (id. at 50). The Company asserts that it has the flexibility to eliminate more than 80 percent of its existing domestic gas commodity purchase contracts in less than twelve months (id.). In the case of the Company's Canadian contracts that bundle supply and capacity, Boston Gas is currently releasing to transportation customers a pro rata share of capacity pursuant to the Company's mandatory capacity-assignment program (id.). If firm sales customers do not migrate to transportation at the rate assumed in the base case scenario, the Company states that it will continue to procure commodity supply resources (id.).

Under the mandatory capacity-assignment program, the Company will assign upstream and storage capacity on behalf of customers (id.). Recall rights to the capacity are retained by the Company to ensure the supply (id. at 51). Regarding the renewal of those capacity contracts, the Company states that it will evaluate the overall need and cost effectiveness of using such capacity to serve all customers regardless of whether they are firm sales or transportation customers (id.). The Company also plans to negotiate, both with marketers and pipelines, any contracts coming up for renewal in order to secure sufficient capacity at terms and prices that meet market conditions (id.).

5. Sensitivity Analysis

In the presence of inherent uncertainties in both the demand and the forecast, Boston Gas aimed to ensure the availability of adequate and reliable resources (id. at 51). The Company used a sensitivity analysis to determine the potential effects of the uncertainties (id.). The Company built two scenarios with respect to its base case forecast: a high-demand and a low-demand scenario (id.).

a. Development of Demand Scenarios

The Company identified the uncertainty of fuel prices and economic activity as key variables from which uncertainties may originate and analyzed their effect on its demand forecast (id. at 52).

i. High-Demand Scenario

The Company's high-demand scenario assumes household growth and employment rates that are 50 percent higher than the base case (id. at 52). Like the base case, the high-demand scenario assumes that the average growth rate of households is 1.2 percent and the average employment growth rate is 1.9 percent (id.). This scenario also assumes that gas and oil prices will remain unchanged during the forecast period (id.). The high-demand scenario yields 16,954 BBtu of gross and 10,286 BBtu of net incremental load additions over the forecast period (compared to 14,427 of gross and 7,863 of net in the base case) (id. at

Chart I-B13 (revised)).

ii. Low-Demand Scenario

For the low-demand scenario, Boston Gas assumes that the variables used in the Company's forecast will grow by half of what was assumed in the base scenario (id. at 53). Therefore, in the low-demand scenario, the growth rate of households averages 0.4 percent per year while the employment growth rate drops to 0.6 percent per year on average (id.). In addition, the Company assumed that gas commodity prices will remain at the high levels experienced throughout 1996 and into the winter of 1996-1997 which contributed to the low demand in the forecast period (id.). Boston Gas indicates that this lower economic growth coupled with higher gas commodity prices will result in 2,392 BBtu of gross and 993 BBtu of net average annual load additions over the same period (id. at Chart I-B-12 (revised)).

6. 1997 vs. 1994 Demand Forecast

The Company compared its 1997 current forecast of average annual load additions with the 1994 forecast presented in Boston Gas Company, D.P.U. 94-109 (Phase 2) (1996) (Exh. BGC-1, at 53). This comparison indicates that, while the actual total gross load additions were lower in the 1997 forecast, the net load additions were higher due to seasonal firm sales (id.). The Company forecasts annual average gross load additions at 3,402 BBtu and 2,886 BBtu for the years of 1995-1999 and 1998-2002, respectively (id. at 53-54).

7. Forecast vs. Actual Load Additions

The Company compared actual and forecast gross load additions for the period

1992-1996 (id. at 54). The results show the residential projections were nine percent higher, C&I sector projections six percent higher, and total projections seven percent higher on average than actual realizations (id.). The Company argues that the magnitude of these disparities was largely caused by unusually large deviations in 1993 (14 percent) and in 1995 (23 percent) (id.). Boston Gas claims that the 1993 disparity was due to a work stoppage and consequent reassignment of personnel (id.). Boston Gas claims that the 1995 disparity was due to a limitation in the specification of its model.[(13)] In the absence of these two outliers, the difference between the total forecast and actual load additions is minus one percent (id. at 55).

8. Analysis and Findings on Demand Forecast

For the purposes of the demand forecast, Boston Gas: 1) developed separate traditional and non-traditional market forecasts which it then summed to yield the total demand projections; 2) applied its end-use modeling method for its traditional customers and estimated the total energy demand by end-use and fuel type;[(14)] 3) used traditional multiple linear regression analysis in forecasting demand; and 4) prepared separate gas consumption estimates for existing and new categories of residential and C&I customers. This method employs traditionally proven techniques.[(15)] With regard to the predictive power of its model, the Company employed an ex post analysis which compared actual and forecast gross load additions for the historical five year period of 1992-1996. This analysis indicates that, in the absence of two outlier years, the resulting total forecast load additions deviated from the actual by minus one percentage point. Therefore, the Department finds the Company's demand forecast to be appropriate, reviewable and reliable.

9. Method for Projecting Sendout

a. Description

To project sendout, the Company converted forecasted levels of incremental sales to incremental sendout requirements by adjusting forecasted incremental sales for unaccounted-for gas (id. at 56, Chart I-5-1). The Company first established a "baseline sendout requirements" model by regressing daily firm sendout on independent variables such as temperature and day of the week for the most recent split year (id. at 56). Next, Boston Gas added the incremental sendout for each plan year to the baseline sendout and obtained the forecast of total sendout requirements over the forecast period (id. at Chart I-C-5 (revised)). Finally, as discussed in Section III(D), below, the Company optimized its portfolio by employing its own SENDOUT® model (Exh. BGC-1, at 56).

The Company's baseline model is a multiple linear regression model in which the actual firm sendout is regressed against: 1) EDD data; 2) EDD data lagged by one day; and

3) a weekend dummy variable (id.). The units of measurement for the variables are: 1) MMBtu per day for the daily sendout dependent variable; and 2) EDD per day for the EDD-related variables (id. at 57). The baseline equation data covers April 1, 1996, through March 31, 1997 (id.). The Company indicates that the adjusted R-squared is 0.992, all of the t-statistics are greater than 2.0, and signs of the coefficients of the independent variables are as expected (id.).

The Company claims that the inclusion of the one-day lagged EDD variable (i.e., the previous day's EDD) contributes to the explanatory power of the model (id.). The Company states that the positive sign of the coefficient indicates that heating requirements increase as two consecutive days of cold weather cool down structures more than a single day (id.). The value of this variable was set to zero for the months of July and August, since there is no heating requirement in the summer (id.).

The weekend dummy variable measures the effect of weekends on daily load. (id.). The Company argues that the negative coefficient of this variable shows a load reduction during weekends, all other factors being equal (id.).

In Boston Gas Company, D.P.U. 94-109 (Phase I) (1996), the Department required the Company to provide justification for its assumption that there is a linear relationship between EDD and sendout (at very cold EDD levels) for design-day planning purposes (id. at 58). The Company argues that, since the error terms appear to have no functional relationship to EDD, its assumption of linearity holds (id. at 59).

The Company examined the so-called "bend-over" effect in its service territory which suggests that the relationship between load and temperature may not hold for periods of severe weather because the fuel intake for gas heating equipment may peak and level-off at extremely cold temperatures (id. at 60). For this test, the Company reviewed the heating unit design requirements of the Massachusetts Building Code ("Building Code"), and concluded that there exists a linear relationship between EDD and sendout even at very cold EDD levels (id.).(16) The Company states that heating contractors typically install heating units for residential units designed to meet the heating requirements of a household at 88 EDD (id.). Further, the Company argues that since the Building Code requires a detailed analysis of buildings prior to their construction, there is reasonable assurance that the installed equipment will meet load requirements at degree day levels in excess of design conditions without a leveling off in sendout per incremental EDD (id.).

The normal and design firm sendout levels for the 1996-1997 split year indicate 77,606 BBtu for normal-year and 82,321 BBtu for design-year (id. at 60-61, Chart I-C-5(revised)). The Company's sendout requirements forecast projects that total firm sendout will increase over the forecast period by 8,053 BBtu (10.4 percent) under normal conditions (id. at 61). The Company's estimate of increase for traditional markets is 9,318 BBtu (12.6 percent) (id. at Chart I-C-5(revised)).(17)

b. Analysis and Findings

The Company has developed a statistically sound methodology to project sendout. This is supported by the strong statistics such as the adjusted R-squared, and the t-statistics for the variables. Consequently, the Department finds that the Company's model is appropriate, reviewable and reliable for forecasting the normal-year, design-year and design-day sendout for the residential and C&I classes.

Regarding the Company's assumption of linearity in the relationship between EDD and sendout, after review of the Company's analysis of the "bend-over" effect, we find the Company's conclusion that the effect does not apply to its service territory to be reasonable.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

The Department is required to ensure "a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." G.L. c. 164, § 69I. In fulfilling this mandate, the Department reviews a gas company's supply planning process and the two major aspects of every utility's supply plan -- adequacy and cost.(18) Commonwealth Gas Company, D.P.U. 92-159, at 53; Colonial Gas Company, D.P.U. 93-13, at 49-50; 1992 Boston Gas Decision, 25 DOMSC at 201.

The Department reviews a gas company's five-year supply plan to determine whether the plan is adequate to meet projected normal year, design year, design day, and cold-snap firm sendout requirements.(19) In order to establish adequacy, a gas company must demonstrate that it has an identified set of resources that meet its projected sendout under a reasonable range of contingencies. If a company cannot establish that it has an identified set of resources which meet sendout requirements under a reasonable set of contingencies, the company must then demonstrate that it has an action plan which meets projected sendout in the event that the identified resources will not be available when expected. Colonial Gas Company, D.P.U.

96-18, at 31; Commonwealth Gas Company, D.P.U. 92-159, at 54; Colonial Gas Company, D.P.U. 93-13, at 50.

In its review of a gas company's supply plan, the Department reviews a company's overall supply planning process. An appropriate supply planning process is essential to the development of an adequate, low-cost, and low environmental impact resource plan. Pursuant to this standard, a gas company must establish that its supply planning process enables it to

(1) identify and evaluate a full range of supply options, and (2) compare all options -- including C&LM -- on an equal footing. Colonial Gas Company, D.P.U. 96-18, at 31; Commonwealth Gas Company, D.P.U. 92-159, at 54; Colonial Gas Company, D.P.U. 93-13, at 51; 1992 Boston Gas Decision, 25 DOMSC at 202.(20)

Finally, the Department reviews whether a gas company's five year supply plan minimizes cost. A least-cost supply plan is one that minimizes costs subject to trade-offs with adequacy and environmental impact. Commonwealth Gas Company, D.P.U. 92-159, at 55; Colonial Gas Company, D.P.U. 93-13, at 51-52; 1992 Boston Gas Decision, 25 DOMSC at 203. Here, a gas company must establish that application of its supply planning process has resulted in the addition of resource options that contribute to a least-cost plan.

B. Previous Supply Plan

On June 2, 1994, the Company filed a petition for approval of its 1994 Forecast and Supply Plan encompassing the years 1995-1999. The petition was docketed as D.P.U. 94-109. On November 23, 1994, the Department bifurcated the proceeding in order to investigate forecasting and planning standards in the initial phase ("Phase I"), and supply planning and DSM programs in a second phase ("Phase II"). On January 18, 1996, the Company filed a Motion to Stay ("Motion") the Department's directives in D.P.U. 94-109 (Phase I) which required Boston Gas to file a supply plan on or before February 5, 1996, as part of its Phase II filing. The Company stated that, because it expected to file a comprehensive

performance-based rate-making and service unbundling plan ("PBR") by June 1996, it would not be useful to require the Company to proceed with a supply plan filing at that time (Motion at 2-3). The Department denied the Company's Motion (D.P.U. 94-109 Phase II, at 4 (February 23, 1996)).

On April 16, 1996, the Company filed a Motion for Approval of Offer of Settlement ("Settlement") relating to Boston Gas' supply plan. As part of the Settlement, the Company stated that it would continue to manage its existing resource portfolio to meet its sendout requirements in a least-cost manner. Further, the Settlement provided that the Company would continue to attempt to maximize the use of its capacity and minimize gas costs, while maintaining the flexibility required to manage supply and demand uncertainties. D.P.U.

94-109, (Phase II) at 4 (1996). The settling parties neither conceded nor denied: 1) the adequacy or reliability of the Company's Phase II supply plan filing; 2) the reviewability or appropriateness of the Company's planning method; or 3) the adequacy of the Company's resource portfolio to meet its design requirements (Settlement at 3). On May 17, 1996, the Department approved the Settlement based on its consistency with Department policy and public interest (id. at 7).

C. Base Case Supply Plan Resources

Base case supply plan resources are the Company's resources available to meet forecasted firm sendout requirements under design conditions while minimizing costs under normal weather conditions. The Company's capacity resources are divided into four primary areas: 1) pipeline capacity; 2) storage contracts; 3) gas supply contracts; and 4) supplemental resources (Exh. BGC-1, at 78).

1. Pipeline Transportation

The Company's capacity resources comprise: 1) long haul domestic capacity (contracts totaling approximately 242,000 MMBtu per day); 2) short haul capacity used to transport gas from underground storage fields in Pennsylvania and New York to Boston (contracts totaling approximately 167,000 MMBtu per day); and 3) short haul capacity from the United States-Canada border to Boston (contracts totaling approximately 54,000 MMBtu per day) (id.).

The total pipeline capacity contracts available to the Company to meet system requirements and to fill underground storage are 463,000 MMBtu per day. The Company's capacity contracts comprise the following: 1) eleven firm tariff service contracts with Algonquin Gas Transmission Company (280,019 MMBtu per day of firm service entitlements); 2) three short and long haul firm transportation contracts from CNG, Texas Gas Transmission Corporation ("Texas Gas"), and Transcontinental Pipeline Company together yielding 41,009 MMBtu per day of capacity; 3) seven firm tariff service contracts with Texas Eastern Transmission Company ("Texas Eastern") totaling 214,892 MMBtu per day of capacity; 4) two firm transportation contracts with the Koch and NORAM gas pipelines(21) whose aggregate total is 73,847 MMBtu per day of capacity; 5) one firm transportation contract(22) with Mobile Bay Pipeline Company for 30,085 MMBtu per day of capacity; 6) nine firm transportation contracts with Tennessee Gas Pipeline(23) ("Tennessee") whose aggregate entitlements total 128,322 MMBtu per day; and 7) one firm transportation service contract from Iroquois Gas Transmission System totaling 43,600 Mcf (id. Table G-24A).

2. Storage Contracts

Boston Gas states that its pipeline storage enables it to serve peak load requirements with lower-cost, off-peak gas, and to manage minimum take requirements. In addition, the Company states that storage is a valuable means of managing short-term fluctuations in demand (id. at 90). The Company holds underground firm storage agreements with six companies: Tennessee, Texas Eastern, Honeoye Storage Corp., Penn-Energy Corp.

("Penn-Energy"), CNG, and Distrigas of Massachusetts ("DOMAC"). On an aggregate level, the maximum daily withdrawal quantity ("MDWQ") for the Company's underground storage contracts is 298,930 MMBtu(24) per day (see Exh, BGC-1, at 90-93). The Company's aggregate level of maximum daily injection quantity ("MDIQ") of its underground storage contracts is 100,567 MMBtu per day (id.).

3. Gas Supply Contracts

The Company states that it has supply contracts whose terms exceed one year (id.

at 94-95, Table G-24). Approximately one-third of the Company's long-haul delivered commodity supply consists of: 1) two domestic contracts,(25) and 2) three Canadian contracts. The Company has a long-term commodity contract with ANE providing for an annual contract quantity ("ACQ") of 3,139,000 MMBtu, a maximum daily quantity ("MDQ") of 8,600 MMBtu, and a minimum annual take requirement of 1,883,400 MMBtu. This contract began on November 1, 1996, and expires on November 1, 2003 (Exh. BGC-1 at 95). The Company also has a long-term commodity contract with Boundary Gas, Inc. that has an ACQ of 3,844,545 MMBtu, an MDQ of 10,533 MMBtu, and a minimum annual take requirement of 2,306,727 MMBtu (id.)

The Company's three Canadian(26) commodity contracts are follows: 1) Imperial Oil Resources expiring in 2007 with a 75 percent annual take requirement. The ACQ and MDQ are 12,775 BBtu, and 35,000 MMBtu respectively; 2) Alberta Northeast, Ltd. expiring in 2006 with a 60 percent annual take requirement. The ACQ and MDQ are 3,139 BBtu and 8,600 MMBtu respectively; and 3) Boundary Gas, Inc. expiring in 2003 with a 60 percent annual take requirement (id. at 95-96). The ACQ and MDQ are 3,844.5 BBtu and 10,533 MMBtu respectively (id.). In addition to firm domestic and Canadian supply contracts, Boston Gas also has an agreement with DOMAC to purchase up to 2,000,000 MMBtu of liquified natural gas ("LNG") per year during the period March 15 through November 15 (id. at 96).

4. Supplemental Resources

The Company's supplemental resources are used to meet seasonal requirements in excess of pipeline resources (id.). According to the Company, these resources can be quickly brought on-line and are, therefore, used to meet hourly fluctuations in demand, maintain deliveries to customers, and balance pressures across portions of the distribution system during periods of high-demand (id.). The Company operates three LNG facilities(27) with an aggregate storage capacity of 3,140 MMcf (or 3,140,000 MMBtu) (id. at 97). The total MDQ for these LNG facilities is 291,400 MMBtu per day with 77.5 MMcf per day emergency standby vaporization (id.).

Through its Massachusetts LNG, Inc. subsidiary ("Mass LNG"), the Company had leased LNG tanks located in Lynn and Salem, Massachusetts from INLC under an agreement dated June 1, 1972 (id. at 75). Although the lease expired on June 30, 1997, Mass LNG continued to operate the tanks under an agreement with INLC (id. at 75). On April 30, 1999, Boston Gas and INLC entered into a new lease agreement ("Lease Agreement") which provides for Boston Gas' continued operation of its Lynn and Salem LNG facilities through June 30, 2014 (see Letter from Boston Gas Company regarding INLC, at 1, June 24, 1999).

In addition to the LNG facilities, the Company operates propane facilities with an MDQ of 70,000 MMBtu, standby of 37,300 MMBtu per day, and storage capacity of 158,400 MMBtu. Boston Gas states that its propane supply output is limited by on-site storage capacity, trucking limitations, and necessary flow-by of gas (Exh. BGC-1, at 98). The Company's ability to withdraw is only limited by on-site storage, trucking limitations, and the necessary flow-by of natural gas (id.).

D. Resource Management

1. Standard of Review

The Department has determined that a supply planning process is critical in enabling a utility company to formulate a resource plan that achieves an adequate, least-cost and low environmental impact supply for its customers. D.P.U. 94-14, at 36; D.P.U. 93-13, at 70; 1992 Boston Gas Decision at 223; 1990 Boston Gas Decision at 388. The Department has noted that an appropriate supply planning process provides a gas company with an organized method of analyzing options, making decisions, and re-evaluating decisions in light of changed circumstances. Id. For the Department to determine that a gas company's supply planning

process is appropriate, the process must be fully documented. D.P.U. 93-13, at 70; 1992 Boston Gas Decision at 223; 1987 Berkshire Gas Decision at 84.

The Department's review of a gas company's process for identifying and evaluating resources focuses on whether the company: (1) has a process for compiling a comprehensive array of resource options -- including pipeline supplies, supplemental supplies, DSM, and other resources; (2) has established appropriate criteria for screening and comparing resources within a particular supply category; (3) has a mechanism in place for comparing all resources, including DSM, on an equal basis, i.e., across resource categories, and (4) has a process that as a whole enables the company to achieve an adequate, least-cost, and low environmental impact supply plan. D.P.U. 94-140, at 37; D.P.U. 93-13, at 70; 1992 Boston Gas Decision at 224; 1990 Boston Gas Decision at 54-55.

As set forth in Section III.A, above, the Department reviews a gas company's five-year supply plan to determine whether it minimizes cost, subject to trade-offs with adequacy and environmental impact. D.P.U. 94-140, at 37; D.P.U. 93-13, at 88; 1992 Boston Gas Decision at 236; 1987 Boston Gas Decision at 214. A gas company must establish that the application of its supply planning process, including adequate consideration of DSM and consideration of all resource options on an equal basis, has resulted in the addition of resource options that contribute to a least-cost supply plan. D.P.U. 94-140, at 37; D.P.U. 93-13, at 83; 1992 Boston Gas Decision at 233; 1986 Berkshire Decision at 115. As part of this review, the Department requires gas companies to show, at a minimum, that they have completed comprehensive cost studies comparing the costs of a reasonable range of practical supply alternatives prior to selection of major new resources for their supply plans. D.P.U. 94-140, at 37; D.P.U. 93-13, at 89; 1992 Boston Gas Decision at 236; 1986 Gas Generic Order at

100-102.

2. Identification of Resource Options

The Company states that it is engaged in a continuous process to manage its portfolio, maximize the use of its capacity, and minimize the cost of gas, while maintaining flexibility to meet changing weather conditions and the uncertainties of the competitive demand and supply markets (Exh. BGC-1, at 99). The Company indicates that its resource management process is comprised of: 1) identifying the volume and duration of capacity available after core requirements have been met; 2) identifying the potential market options for this capacity; and 3) matching opportunities to the available capacity and prioritizing their ability to maximize value and to reduce the cost of gas to customers (id.). The Company uses its resource plan output from its SENDOUT® Model to maximize its resource management process. The Company states that since 1993, it has achieved an approximate $38 million reduction in

gas-related costs by contract restructuring, and engaging in various market activities such as sales-for-resale, interruptible sales, capacity release, and downstream capacity restructuring (id. at 99-106).

The Company states that in an era of customer migration, it seeks to utilize its resources as efficiently as possible in an effort to minimize supply and capacity costs. To this end, the Company states that it strives to increase throughput in its core firm market segments to spread fixed-costs over a larger customer base (id. at 107). Further, the Company states that it attempts to increase residential and C&I market share (via existing incentive programs) while pursuing non-core contracts for customers for whom tariff rates are non-competitive (id.).

E. Normal Year and Design-Day

1. Description

The Company presented three supply-plan demand scenarios (low-case, base-case, and high-case) to meet its forecasted design-year and design-day sendout requirements throughout the forecast period (see Exh. BGC-1, Tab IV). The Company states that it can meet the

low-case and base-case design-year and design-day sendout requirements throughout the forecast period without the need to purchase additional LNG (Exh. BGC-1, at 71, 73).

2. Cold-snap Adequacy

The Department has defined a cold-snap as a prolonged series of days at or near design conditions. Colonial Gas Company, D.P.U. 93-13 at 66; 1992 Boston Gas Decision, 25 DOMSC at 217. For evaluation purposes, an LDC must demonstrate to the Department that the aggregate resources available are adequate to meet this near-maximum level of sendout over a sustained period of time, and that it has and can sustain the ability to deliver such resources to its customers (id.).

Boston Gas evaluated the ability of its current resource portfolio to meet sendout requirements should a cold-snap occur (Exh. BGC-1 at 73-74). The Company tested the

cold-snap performance of its resources with a two week period encompassing the last two weeks of February.(28) Using the SENDOUT® Model, the Company evaluated its cold-snap adequacy by modeling daily sendout and observing the predicted resource usage over a specified set of EDD (Exh. BGC-1 at 74). To generate its 14-day cold-snap scenario, the Company selected the coldest actual period during February 15th-28th in the years 1976-1995 (id.). The Company then scaled-up the actual daily data during this time frame to model a two-week period of design cold-snap. The Company calculated the probability of occurrence for its cold-snap scenario to be once in 50 years. Using the base-case demand, the Company then analyzed the effectiveness of its portfolio in meeting normal weather (November 1 - November 14), the two week cold-snap, followed by normal weather (id.). The results of the cold-snap simulation using the SENDOUT® Model indicate the Company's ability to meet cold-snap conditions with its existing portfolio resources (id.).

F. Positions of the Parties

Prior to the signing of the new Lease Agreement for the Lynn and Salem LNG facilities, the Attorney General expressed concern that the Company failed to provide adequate assurances that it would be able to maintain system reliability at a reasonable cost should these LNG facilities become unavailable (Attorney General Brief at 7).(29)

G. Analysis and Findings

As evidenced by the scenario-testing ability of the SENDOUT® Model, the Company has adequately demonstrated that it has in place reasonable processes by which it develops resource planning strategies to maintain reliable, least-cost service to its firm sales customers. The Company's SENDOUT® Model allows it to identify, in a reasonable manner, a variety of pipeline and supplemental supply and capacity options based on a multitude of criteria. Coupled with the Department's earlier review of the Company's design-year and design-day forecasting methods, an integral element to resource supply planning, the Department finds the Company's resource supply planning processes for projecting normal-year, design-year, design-day, and cold-snap conditions to be reviewable, appropriate, and reliable.

The Company's plans to use propane and LNG resources to meet seasonal needs in excess of pipeline entitlements are reasonable relative to demand and sendout projections and are, therefore, approved. The Attorney General's argument regarding LNG reliability is moot in light of the Lease Agreement providing for the continued operation of the Lynn and Salem LNG facilities through June 30, 2004.

The Department finds that Boston Gas has properly identified adequate resources to meet the Company's firm sendout requirements throughout the forecast period. The Department further finds that Boston Gas has developed an appropriate planning process. Accordingly the Department approves the Company's supply plan for the split years

1997-1998 through 2001-2002.

IV. ORDER

After due notice, hearing and consideration, it is

ORDERED: That Boston Gas Company's petition for approval of its long-range sendout forecast and supply plan be and hereby is approved; and it is

FURTHER ORDERED: That Boston Gas Company comply with all of the directives contained herein prior to filing its next long-range forecast and supply plan; and it is

FURTHER ORDERED: That Boston Gas Company shall file its next long-range sendout forecast and supply plan with the Department by September 30, 2001.

By Order of the Department,

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James Connelly, Chairman

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W. Robert Keating, Commissioner

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Paul B. Vasington, Commissioner

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Eugene J. Sullivan, Jr. Commissioner

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Deirdre K. Manning, Commissioner

1. On July 15, 1999, the Department approved the acquisition of Colonial Gas Company by Eastern Enterprises, parent company to Boston Gas Company and Essex Gas Company. See Eastern-Colonial Merger, D.T.E. 98-128 (1999). Boston Gas, however, filed this Forecast and Supply Plan prior to the petition for approval of the merger. Therefore, our review of Boston Gas' Forecast and Supply plan is based on the information available at the time of this filing. We note, however, that we expect Boston Gas, Colonial Gas and Essex Gas to file a joint Forecast and Supply Plan that reflects the combined planning of the three companies. Moreover, we note that the Attorney General's Office has appealed the Department's approval of the merger to the Supreme Judicial Court. See Docket No. SJ-1999-0384.

2. A cold-snap is a prolonged series of days at or near design conditions. D.P.U. 93-13, at 66; Boston Gas Company, 25 DOMSC 116, at 217 (1992); Commonwealth Gas, 17 DOMSC 71, at 137 (1998) ("1998 Commonwealth Gas Decision").

3. A degree day ("DD") is a measure of the coldness of the weather experienced, based on the extent to which the daily mean temperature falls below sixty-five degrees Fahrenheit. An EDD takes into account wind speed in determining the coldness of the weather. Colonial Gas Company, D.P.U. 96-18, at 6 (1998).

4. Probability-weighted costs of damages refers to the probability of exceeding the mean peak EDD of 66.8 established by taking the average of each of the coldest days recorded over the last twenty-five heating seasons (Exh. BGC-1, at 13, Chart 1-A-5).

5. Residential relight expenses are estimated to be $66.00 per customer multiplied by the number of customers interrupted (Exh. BGC-1, Chart 1-A-3).

6. Residential freeze-up costs are based on information provided by Marsh & McLennan, a property loss consultant (Exh. BGC-1, Chart 1-A-4).

7. To estimate the cost of losses, the Company used the gross state product ("GSP") per day, as reported by the Commonwealth of Massachusetts Division of Energy Resources, weighted to account for the size of its service territory and the share of natural gas versus other fuels (Exh. BGC-1, at 18).

8. According to the Company, gas sendout during the heating season is 59 percent residential and 41 percent C&I (Exh. BGC-1, at 19). Boston Gas stated that all shortfalls due to lack of supply during extreme weather could be assigned to the C&I sector (id.) The Company divided the shortfall value by the C&I requirement to derive the fractional amount of C&I customers that would suffer curtailment. All amounts for a given EDD scenario were summed to determine the total number of shortfall days and the equivalent in

curtailments that would occur (id. at 20). The number of shortfall days were then multiplied by the GSP per day for the C&I customer base (id.). The Company weighed these results by the probability of occurrence to determine the probability weighted cost of damage (id.).

9. The ECP establishes four steps for reducing load requirements: 1) request dual-fuel customers to convert to alternate fuel; 2) solicit supplies from dual fuel and firm customers; 3) request heating customers reduce their thermostat settings; and 4) request State officials to notify non-essential facilities to reduce gas consumption (Exh. BGC-1, at A.1.15).

10. An "end-user" is defined as a customer who actually uses or burns natural gas, as opposed to one who sells or re-sells it. Traditional end-users include the residential, apartment complex, and C&I sectors.

11. "The price elasticity of demand is a measure of how sensitive quantity demanded is to a change in price. It can be defined as the percentage change in quantity demanded divided by the percentage change in price." Microeconomic Theory and Applications (1986), Edgar K. Browning and Jacquelene M. Browning, p. 89, 2nd Edition (Little Brown).

12. These gross additions to total throughput include 12,955 BBtu in the traditional core markets and 1,472 BBtu in the NGV market (Exh. BGC-1, at 29).

13. The Company indicates that the model lagged into 1996 some of the load additions that actually occurred in 1995 (Exh BG-1, at 55).

14. This is a "bottom-up" approach that simulates individual decision-making for the choices of energy equipment, energy sources and consumption levels.

15. The Department notes, however, that the energy consumption per employee input to the Company's forecast may be misleading for the industrial sector. Factor intensities may vary among different technologies and this could lead to an erroneous estimation of the energy consumption figures. In this context, we note that the output variable might have provided a better choice for the Company's model.

16. The Company, however, indicated that "[t]his effect has been observed in other LDCs' territories" (Exh. BGC-1, at 60).

17. The difference is due to decrease in seasonal gas contracts (see Exh. BGC-1, Chart I C-5).

18. G.L. c.164, § 69I also directs the Department to balance cost considerations with environmental impacts in ensuring that the Commonwealth has a necessary supply of energy. Colonial Gas Company, D.P.U. 96-18, at 31; Commonwealth Gas Company, D.P.U. 92-159, at 53; Colonial Gas Company, D.P.U. 93-13, at 50.

19. The Department's review of reliability, another necessary element of a gas company's supply plan, is included within the Department's consideration of adequacy. See Colonial Gas Company, D.P.U. 93-13, at 50, n. 22; 1992 Boston Gas Decision, 25 DOMSC at 201, n. 87; Boston Gas Company, 16 DOMSC 173, at 214 (1987).

20. G.L. c. 164, § 69I, requires a utility company to demonstrate that its long-range forecast "include[s] an adequate consideration of conservation and load management." Initially, the Siting Council reviewed gas C&LM efforts in terms of cost minimization issues. In the 1988 Commonwealth Gas Decision, 17 DOMSC at 122-126, the Siting Council expanded its review to require a gas company to demonstrate that it has reasonably considered C&LM programs as resource options to help ensure that it has adequate supplies to meet projected sendout requirements.

21. According to the Company, these contracts serve to feed key gas receipts on the Texas Eastern pipeline and expire in November 1998. The contracts also provide the Company some ability to transfer gas between the long-haul contracts on the Texas Gas and Tennessee systems in the event of a curtailment (Exh. BGC-1, at 86). The Company is investigating whether there would be any cost savings associated with letting these contracts expire and purchasing gas delivered to these points (id.).

22. This contract expires in November 1998. The Company is investigating whether there would be any cost savings associated with letting this contracts expire and purchasing gas delivered to these points (Exh. BGC-1 at 86).

23. The Company states that the Tennessee contracts purchase gas from various suppliers on each of the three legs of the system (Exh. BGC-1, at 86).

24. It should be noted that 100,000 MMBtu of the above-mentioned MDWQ is part of a storage service agreement with Distrigas for storage of liquified natural gas with an associated vaporization of 98,000 MMBtu per day (net of fuel). Also, three of the underground storage contracts (Tennessee, Texas Eastern, and Penn-Energy), have "ratchet-down provisions" allowing the Company to lower the MDWQ based on the percentage of inventory withdrawal (see Exh. BGC-1, at 90-93).

25. Twenty percent of the Company's domestic supplies are purchased pursuant to long- term contracts. The remaining eighty percent are purchased based on short-term or spot contracts. The Company argues that this supply mix strategy minimizes its exposure to fixed costs enabling it to better match supply to short-term changes in demand (Exh. BGC-1, at 68, 94-94).

26. The Company states that these contracts are fundamental to serving the pipeline expansion projects serving the Northeast (Exh. BGC-1, at 90-93).

27. The Company's three supplemental LNG resources are Salem Mass LNG, Commercial Point, and Lynn Mass LNG with storage capacities of 1,000, 1,140, and 1,000 MMcf respectively. Exh. BGC-1 at 97.

28. The Company states that its portfolio is most severely tested when a cold-snap occurs late in the heating season when storage inventories are depleted and deliverability may be ratcheting down. According to the Company, the last two weeks of February represents such a time (BG-1, at 73-74).

29. Briefs were filed prior to the signing of the Lease Agreement.